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Dear Ms. Savage,

Thank you for taking the time for my recent phone calls, and allowing me the opportunity to submit comments for consideration with respect to the proposed changes to TAC Title 1 Part 16 Chapter 3 Rule 3 §§13, 99, 100 regarding casing/cementing requirements. I regret that I did not know about the proposed rule changes earlier so that I might have prepared more thorough and well-written comments. I hope that I am able to make the essential points of my comments clear and that the RRC has time to consider them in its current deliberations.

Given the time limitations at hand, I will limit my comments to those related to the proposed regulatory changes that relate to or derive from hydraulic fracturing treatment (HFT) of wells. To begin let me consider the preamble discussion of the proposed new sections (a)(2)(L) and (a)(7)(D) regarding minimum separation wells. The preamble explains,

"The Commission proposes new subsection (a)(7) relating to additional requirements for wells on which hydraulic fracture treatments will be conducted. . . . The Commission selected a distance of 1,000 vertical feet as the default *demarcation point for minimum separation wells* after reviewing "Hydraulic Fracture-Height Growth, Real Data," (by Kevin Fisher and Norm Warpinski, SPE 145949, SPE Production & Operations, Volume 27, Number 1, February 2012, pp. 8-19) and "Hydraulic fractures: How far can they go?" (by Davies, R.J., et al, Marine and Petroleum Geology (2012))."

I have reviewed the two referenced articles, as well as numerous others, and would like to submit for your consideration the following points.

1. The articles mention at least three sources of error in the microseismic data reported. There appeared to be only one attempt to estimate the level of only one type of such errors, which was put at <20%. One would presume that the other error sources would be random and cumulative in effect. Hence, the maximum possible error is then likely well over 20%. In addition, Davies et al reported that for the period from 2001-2010 the maximum upward stimulated fracture propagation in the Barnett Shale was around 1900 feet (≈588 meters). If, in the name of reasonable caution, one were to allow a 20% error on the maximum 1900-foot fracture height, then it would seem to follow that "the default demarcation point for minimum separation wells" should be 1900 feet plus an error

allowance of at least 20%, or at least 2250 feet. Further, to remain in accord with the sound principle in the current regulations with regard to protection of aquifers, this separation distance should be between the lateral bore that is to be hydraulically fractured and the deepest known or anticipated zones that are “correlative and/or hydrologically connected to zones that contain usable-quality water”. As I will discuss below this greater minimum separation distance still may not provide a reliable assurance of protection of aquifers or zones bearing water, hydrocarbon or other resources between the hydraulically fractured gas well lateral bore and known aquifers.

2. Review of the graphic presentations of data in Fisher and Warpinski suggests there is no reason that one should assume that the extent of HFT induced fractures in a given gas field are in any way predictive of the likelihood of unusually extensive HFT- induced fractures anywhere else in the same field. That is, the lack of vertically extensive HFT fractures in a number of previous wells in a field does not provide any assurance that a high fracture will not result from the next HFT operation on another well in that gas field. It would seem to follow that if the formations and rock types are consistent (in their potential inconsistencies), then vertical and lateral bore hole integrity similarly cannot be predicted for the next well in the same field based on previous wells in that field. It, therefore, seems inadvisable to allow any exceptions to any measures intended to assure well structural integrity in minimum separation wells (a)(7)(D)(v).

3. I would like to suggest that the RRC consider that its long history as a regulator of the oil and gas industry in Texas has shaped its institutional perceptions of the potential effectiveness of tried-and-true practices that were developed in and for conventionally drilled oil and gas wells.¹ If one accepts those practices, and the perceptions and design considerations they imply, as effective and reliable, then one needs to consider the implications of those same perceptions and design considerations with regard to directionally drilled HFT wells. The RRC effort to change the current rules seems to confirm that there is an institutional perception that the current rules are inadequate due primarily to the widespread, rapid adoption of directional drilling HFT practices. To restate my concern as a question: Do the currently proposed rule changes adequately address functional differences in the way conventional and unconventional wells interact with their geological matrix?

To begin, consider that the current rules define all matters of interaction between a well and its surrounding medium in terms of the integrity of the casing/cement in zones requiring protection. Under the current regulations all concerns regarding well integrity and fluid flow are assessed by cement evaluation or pressure tests, which can be reasonably regarded as sufficient for conventional wells, in which a vertical pipe is connected to an essentially horizontal reservoir trapped beneath an impermeable, mostly horizontally

¹ Given:

(i) “...as the energy industry matures in the state, the RRC has a greater degree of responsibility ... in plugging and site cleanup of abandoned well locations. If the industry is in a downturn, environmental responsibilities will increase as more abandoned wells and sites fall to the RRC to manage.” (see page 9 at <http://www.sunset.state.tx.us/82ndreports/rct/ser.pdf>)

(ii) the recent estimates that at least 35% of the 1.8 million wells around the globe are leaking (Paul Hopman, SPE Webinar, 27 March 2013).

It follows that the RRC should have great concern about the number of abandoned, leaking wells that will fall to the RRC to manage, and, hence, the adequacy of current tried-and-true practices upon which development of both conventional and unconventional oil and gas wells depend.

oriented formation, a.k.a., caprock. Under these conditions effective seals where the well penetrates the caprock, and between the well casing and surrounding formations between the bottom of the well and the surface, provide reasonable assurance that the target resource will be recovered without undue loss, and other resources in the area will not be impacted. In such a generalized conventional well system, the integrity of all the essential well structures can be tested, and usually corrected if necessary.

There has been a general failure to conceptually recognize that directionally drilled HFT wells are functionally distinctly different from conventional wells. I will focus on shale gas wells as they facilitate distinguishing conventional and directionally drilled HFT wells.

In shale gas wells, the gas is not present in a reservoir in the traditional sense. The gas is present in the shale because the shale itself is impermeable and the gas is trapped within it, not under it – that is why it is necessary to hydraulically fracture the shale. Barring extremely slow, intrinsic release rates, or higher episodic, limited releases due to earthquakes or other natural disturbances, the gas will remain in the shale whether there is an overlying caprock or not. The slowly, intrinsically released gas can rise to accumulate beneath caprocks that do overlay the gas shale to become over geological time gas reservoirs. However, the presence or absence of those caprocks and accumulated conventional gas reservoirs are irrelevant to the release of gas from the shale. Similarly, if there are overlying impermeable-rock formations that are faulted or fractured in such a manner as to be unable to accumulate the rising gas, then they, too, are functionally irrelevant to the release of gas from the shale. The mere presence of such gas-less, impermeable-rock strata above the gas shale and below overlying conventional gas reservoirs clearly suggests that these intermediate, gas-less, impermeable-rock strata are faulted or fractured. It is reasonable to expect that in the thick sedimentary deposits of which gas shales are a part, there will also be permeable strata that will permit relatively rapid movement of gas both vertically and horizontally, in accord with whatever pressure gradients may exist. The entirety of the discussion in this paragraph is supported by various comments in the Davies et al and Fisher and Warpinski papers cited in the preamble, e.g., on page 8 in Fisher and Warpinski, “Most of the larger spikes (both downward and upward) are a result of hydraulic fractures intercepting faults.” On page 17, “Outside factors, such as faults, are regularly observed in the monitoring data.”

The producing section of the shale gas well bore is typically near-horizontal, not vertical. There is no caprock that the well will penetrate and to which the casing can be sealed to assure the gas in the shale, once released, will not migrate out of the shale along any available pathway. The protection that casing and cementing the well bore provides for conventional wells does not address the potential out-of-bore pathways that are suggested by the faulting of otherwise probably impermeable horizons near the gas shale documented in the Fisher and Warpinski and Davies et al papers cited in the preamble.

Those authors, again along with many others, go to some lengths in their discussions to contend that such faults do not reach to the surface because if they did the gas would have been lost over geological time. This proposition is disappointing in two ways. It ignores that just because these faults do not go to the surface does not mean they have not been conducting gas into shallower formations over geological time. Indeed, such gas delivery to shallower formations is a commonly used explanation for the development of conventional gas deposits, again cited by those same authors and many others. Second, it presumes that once the gas has risen to a shallower formation there will be no mechanism or pathway for it to rise further toward the surface. This seems to entirely ignore that other shallower formations may be permeable, again, as indicated by the microseismic data reported by Fisher and Warpinski, or, that shallower, impermeable-rock formations may have faults or fractures independent of those in the faulted formation near the gas shale.

Hence, whether or not the faults contacted by the HFT-induced fractures, or even the HFT fractures themselves, reach the surface is nearly functionally irrelevant to the issue of the occurrence and prevention of out-of-bore flow of gas once the shale has been fractured.

This then leads to another issue of the volumetric capacity of overlying formations to receive and retain gas that has over geological time seeped from the gas shale, or, is released by HFT. Conventional natural gas reservoirs have a finite volumetric capacity that is dependent on the porosity of the reservoir formation and the geometry, orientation and size of the caprock. Presumably in most shale gas fields, the commercially viable conventional reservoirs will likely already have been depleted by conventional wells. Hence, these fields can be expected to have a residual capacity to receive and retain gas rising along out-of-bore pathways from hydraulically fractured gas shale until those reservoirs reach their capacity. At that point natural pathways by which additional gas is lost will become effective, along with artificial paths such as any gas wells that were not appropriately abandoned or have failed structurally due to age or other factors. The lost gas will continue to rise to the next higher caprock to again accumulate to the capacity of that reservoir, and so on until the gas reaches near-surface formations, such as aquifers. If those aquifers happen to lie beneath layers of limited permeability, then gas may accumulate in the aquifer, until the volumetric capacity of the formation involving the aquifer is exceeded. During its rise, the out-of-bore gas flow may or may not find a preferred path to the vertical bore of the HFT shale gas well itself. If such a return-to-bore flow did occur the gas would have a rapid, direct path to shallower potential flow zones, into which it would then flow if pathways and pressure gradients favored such flow. Eventually the gas will reach the surface and escape to the atmosphere.

It also follows that in areas where formations are inclined over considerable distances, the out-of-bore gas flow may migrate over considerable distances through a permeable formation under a caprock to emerge upgradient in an aquifer or at the surface an unforeseeable distance from the HFT shale gas well.

For the reasons just discussed the relationship of conventional wells to the host geological matrix is fundamentally different than for directionally drilled HFT wells. For conventional wells sealing at the well-caprock contact and across contacts with productive or potential flow zones provides considerable protection against loss of control of fluid flows out of the well and its target reservoir. In contrast shale gas wells (as an example of directionally drilled HFT wells) have no specific, distinct, intrinsically associated geological structures that can be so directly exploited to maintain control of the target gas, except the structural integrity of the gas shale itself. Extensive, thorough destruction of that structural integrity is necessary to release the target gas from the shale. It follows that the best approach to maintain control of gas released by HFT would be to assure that the HFT-induced fractures do not extend beyond the boundaries of the gas shale, or into faults through it. Minimally such precise HFT fracturing would require precise knowledge of the locations of faults through and variations in the boundaries of the gas shale formation, and the ability to control the extent of HFT-induced fractures to avoid contact with those faults and boundaries. The literature does not indicate such a fine level of knowledge of the structure of targeted gas shale formations is available, and the data reported in the two preamble-cited articles and numerous others indicate such fine control of the HFT process is not realizable in practice. Indeed, the operational objective seems to be as thorough and extensive HFT fracturing as can be achieved, including beyond the boundaries of the gas shale itself. Consequently, the gas shale itself cannot be regarded as a flow control enabling structural feature that is intrinsically associated with the target gas.

Given that destruction of the structural integrity of the gas shale is an operational necessity, the only hope for a flow-control enabling structure would be an overlying,

contiguous, impermeable caprock formation that extends over and beyond the entire footprint of HFT-fractured zone with sufficient effective gas reservoir capacity to collect and retain any out-of-bore gas flow from the HFT fractured gas shale. Many authors, including those of the preamble-cited papers, contend that the thousands of feet of sedimentary formations overlying gas shales act as such a caprock/reservoir system. This proposition, however, requires that one ignore the reality that thick sedimentary profiles are actually comprised of many strata with distinctly different strengths, permeabilities/porosities, etc. The sedimentary profile will almost certainly contain faults, joints, fractures, inherent porosities, and old wells that will permit potentially rapid gas flows. Again, this heterogeneity of the sedimentary profile is attested to by the same authors that invoke an effective bulk impermeability of the sediment bed as assuring out-of-bore gas flows will be contained. Given the inherent heterogeneity within the sedimentary profile, the proposition that the invoked bulk impenetrability of the sedimentary profile will provide a sequential caprock/reservoir system sufficient to retain out-of-bore flow of gas from every HFT shale gas well seems unlikely. Unfortunately, at present, there appear to be no efforts to distinguish whether or which HFT shale gas wells have out-of-bore gas flows, let alone to assess which shale gas zones would be more or less likely to develop out-of-bore flows when subjected to HFT.

This would seem to leave the RRC in a rather difficult rule-making position. The tried-and-true practices developed in and for conventional wells simply do not address possible, indeed, likely out-of-bore flows that may be inevitable for at least some HFT shale gas wells. Effective casing and cementing of the shale gas well vertical bore would prevent inter-zone flows as anticipated for conventional wells, including any out-of-bore shale gas that might find its way back to the bore. However, prevention of the return of out-of-bore shale gas flow back and into the well bore with casing/cementing would have no effect on the flow out-of-bore shale gas along other pathways and into other zones in the area. Given the level of directional drilling and HFT control measures that are brought to bear on shale gas wells, it would seem to follow as reasonable that post-HFT monitoring measures should be established to evaluate whether out-of-bore flows have developed and if so, how large and in what direction. Colleagues and I are working on such measures, but our work is in early stages. In the interim it would seem reasonable to require continuous recording of field pressure in one or more of the productive or potential flow zones overlying the HFT-fractured area, preferably beginning before drilling/HFT and continuing after the well is completed and in production. Any substantive, sustained increase in field pressure would provide a relatively reliable indication of a flow from a higher-pressure gas source and provide the RRC with a reasonable indication there is need for further investigation into the integrity of the HFT-fractured zone of the shale gas well. Such field pressure changes might or might not be apparent in the bradenhead or other bore-associated pressure measurements.

A word of caution would seem appropriate at this point. Given the foregoing discussion of the differences in the well-to-geological-matrix relationships of conventional compared to HFT shale gas wells, in the event of a well integrity problem in the HFT-fractured zone of a shale gas well the appropriate course of action should be considered carefully. For a conventional gas well with integrity problems in the bore or casing, repair approaches are generally well established and effective. For a HFT shale gas well with a loss of integrity in the HFT-fractured zone, i.e., out-of-bore gas flow, there are no measures for repair. Further, if those flows are impacting properties, aquifers, etc. stopping production from the well will in all likelihood exacerbate the out-of-bore flow due to increasing pressure in the fractured gas shale thereby increasing the impacts on properties, aquifers, etc.

Due to time constraints I must end my comments here. I regret there was not more time for more thorough development. I hope some of the foregoing proves valuable in your considerations of the proposed rule changes and I wish the RRC the greatest success in dealing effectively with the formidable regulatory challenges posed by the current rapid expansion and adoption of directional drilling/HFT well development practices.

Sincerely,
Bryce F. Payne Jr., PhD